COMPUTERIZED AUTOMATION OF OILFIELD PRODUCTION OPERATIONS -AN EXTENSIVE FIVE-YEAR STUDY INTO THE COSTS AND BENEFITS*

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INTRODUCTION

Sun Exploration and Production Company (Sun) conducted an extensive five-year study into the costs and benefits of installing and operating a Supervisory Control and Data Acquisition (SCADA) system. Installed on the Southeast Levelland Unit (SELU), the SCADA system was operated as a full monitoring system. The SELU is a secondary recovery unit located in the Levelland Field in Hockley County, Texas.

The five-year period included 30 months prior to the initial operation and 24 months following full operation of the system. One hundred thirty-four producing wells comprised the data base analyzed in the study. Through the capabilities of the system, Sun's personnel were able to reduce operating costs significantly in several areas. Reduction in subsurface failures per barrel of fluid lifted was 28.6%, and in power consumption per barrel of fluid lifted was 11.3%. An increase in oil and gas production ranging from 3.8% to 13.9% was realized. Actual and potential intangible benefits were also identified.

All factors which could significantly influence the determination of the tangible benefits' true value were identified and considered. The factors considered were drilling effects, workover effects, percent water cut increase, increased water production per well, increased water injection, injection to withdrawal ratio (I/W), rod and tubing life, and the chemical program.

This paper briefly outlines the Unit operations and the SCADA system installation, explains in detail the five-year study, and highlights other intangible benefits provided by the system.

Computerized automation is not new to the petroleum industry[1-3]. Only in the past 10 to 15 years[4] have SCADA systems entered the industry with the capabilities of (1) pump-off control (POC), (2) injection well monitoring (IWM - pressure & rate), (3) automatic well test and data gathering (AWT), and (4) alarm monitoring and reporting.

The cost effectiveness of a complete automation system is often questioned, especially in austere times. With the advent in the petroleum industry of aging secondary recovery projects and increasing awareness of profit margin, methods to increase cost efficiencies in production operations are required. As the SCADA system's benefits are increasingly verified, the potential of computerized automation as a method to improve operational profit margin increases. The main benefits of this type of system have previously been identified with [5-11] and without[12,13] different degrees of post-evaluations. The exact value of the benefits is still questioned throughout the industry. This paper adds solid support to the papers which identify in varying degrees the actual tangible and intangible benefits provided by computerized automation (Table 1).

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This study provided a more detailed and well supported documentation of the costs and benefits resulting from computerized automation of oilfield production operations. The following aspects of this study allow for the greater detail: (1) all factors that could significantly affect the determination of the true value of the benefits were considered (Table 2)..., (2) the effects of the system's operation upon oil and gas production, subsurface failure rates, power consumption, and operational efficiencies were identified on a 134 producing well base over a five-year period.

The values of the tangible benefits and identification of other intangible benefits of computerized automation are included in this paper. Through the least optimistic perspective, Sun applied the values of the three identified tangible benefits and related costs to Sun's economic parameters. The economic analysis performed clearly indicated the system provided benefits to Sun which substantially justified the investment and maintenance costs of the system. Economic analyses vary throughout the industry based upon individual company philosophies. Therefore, the reader must apply the values of these benefits to their own economic guidelines. Neely [5-7], Hunter et al. [8], and Duke [14] provide a detailed description of the installation and functions of the SCADA system.

HISTORY

The Southeast Levelland Unit (SELU) is located in the Levelland Field in Hockley County, Texas. Production is from the San Andres formation at ±4950 feet (1650M). Discovery of the field occurred in 1945 and the Unit was formed in 1964. Water injection was initiated immediately following unitization in 1964.

The SELU encompasses 5,806 acres ($2.35 \times 10^7 m^2$) with 194 producing wells, 116 water injection wells and 1 TA'd well. All producing wells are equipped with electrically-powered beam type pumping units. Production is gathered through 15 individual satellite test stations. Gas is sold and individual well tests are taken at each satellite station. Oil and water are transferred to one central battery. SELU's 1985 daily production averaged approximately 5500 BOPD ($874\ m^3/d$), 18500 BWPD ($2914\ m^3/d$) and 5000 MCFPD ($142\ m^3/d$). Water injection averaged approximately 27500 BWIPD ($4372\ m^3/d$).

The unit was originally operated by Texas Pacific Oil Company. Sun became the operator in July 1980, following Sun's purchase of Texas Pacific's lower 48 states' holdings. Shell Western E&P purchased Sun E&P's interest effective November 1, 1985, and as a result became operator.

Shell Western E&P began their first pilot project with the SCADA system in 1975 on the Denver Unit [8] near Denver City, Texas. Two similar systems were also operated by Sun E&P. The two systems are operated at the Eliasville Unit in Central Texas (1979 installation) and at the Bennett Ranch Unit [14] (1980 installation now operated by Shell) located near Denver City, Texas.

The installation of the SCADA system on the SELU began in late 1980 (Table 3). It was designed and installed to monitor and control both injection and production operations. Initial operations of the pump-off controls (POC) and automatic well tests (AWT) began in July 1982. POC was completely operational by June 1983.

SCADA SYSTEM OPERATIONS

The SCADA system has complete monitoring capabilities. The purpose of the system is to increase operating profit margin through (1) optimization of personnel productivity (more accomplished per person), (2) increased operational effectiveness, and (3) process optimization.

Full exploitation of the system's potential can only be achieved through: (1) correct application of the system, (2) careful planning of the system's application and installation,[15] (3) utilization and management of the system through the motivation, innovation and enthusiasm of quality personnel with positive attitudes, (4) full support of management, and (5) quality maintenance of the system.[16]

The SCADA system is controlled by a Hewlett Packard HP 1000 Series E computer (internal memory of 256K words) and guided by a systems operator.

The SCADA system is divided into two main parts:

1. A pump-off control system (POC)
2. A central data gathering system

The SCADA system provides four basic functions:

1. Producing well monitor and control (POC)
2. Automatic well test and data gathering (AWT)
3. Injection well monitoring (IWM)
4. Alarm monitoring and reporting

The computer with its peripheral equipment (CRT, X-Y plotter, line printer and disc files) is located in the field office. Four Master Terminal Units (MTU) provide communication for the system. One MTU monitors well tests and alarms while the other three MTU's each handle about one-third of the wells. The three MTU's controlling the POC system utilize a four-wire full duplex communication system operating in 4K Baud. Six signals (three command and three responses) may be transmitted simultaneously. The single MTU controlling the data acquisition system utilizes a half duplex communication. Each command on the single MTU must receive a response before another command is given.

A system operator is charged with the daily operation of the system with the following primary duties: (1) to set up and maintain pump off control limits, (2) to set up well test and well diagnostics, (3) to advise the production foreman of alarms, malfunctions and changes in well conditions, (4) to advise automation repairmen of system malfunctions, and (5) to prepare operating reports.

The computer operator analyzes all information received from the computer to ensure accuracy. Hardware problems are referred to the automation repairman. Equipment failures are referred to the lease operators. The computer operator reports all well and other operation problems to the production foreman. Prior to release, all information sent to the district office is manually screened to ensure accuracy.

Operation of the computer can easily be taught to any of the field personnel. As their skills improve, they begin to better utilize the computer and more efficiently carry out their duties. As the computer operator becomes more proficient with the computer, problems are detected faster and more accurately. When a problem is discovered, the possible cause can be isolated to a limited number for the automation repairman or lease operator to check. This greatly reduces the man-hours used in troubleshooting, thereby allowing for more efficient manpower utilization and higher productivity. Some problems such as rod parts, power failures, gas locked wells and sticking pumps are easily detected. Problems such as leaking valves, worn pumps, breaking bridles, belts off a unit, paraffin problems or scale buildup are more difficult to detect but are more easily identified with increased experience.

Detecting paraffin in the flowlines and downhole tubular goods is the latest project of the computer operator. As the paraffin builds in the flowline, the casing pressure increases and the run time decreases. By closely monitoring the run time, the computer operator can detect high flowline pressure result ing from either paraffin or scale buildup. As paraffin builds in the tubing, the peak polish rod load increases and the minimum polish rod load decreases. After a year of surveillance, prediction of the optimum time to hot water each well casing has been established. Therefore, a more economical paraffin removal program exists.

TANGIBLE BENEFITS

To establish the benefits of the system's installation and operation, data outlined in Table 2 were documented from January 1980 to April 1985. Actual operation of the system was established between July 1982 and June 1983. The data compiled from 1980 to 1985 provided a base for data analyses both before and after the SCADA system was completely functional. The effects of the SCADA system installation were determined from the analyses of this data base.

Major tangible benefits providing the reduced cost and increased income from the installation and operation of the SCADA system are attributable to four main areas:

1. Increased oil and gas production
2. Decreased power consumption per barrel of fluid lifted
3. Decreased subsurface failure rate per barrel of fluid lifted
4. Decreased pumping unit repairs and maintenance

Benefits from only three of these four areas were determined accurately by the data gathered in the study. Pumping unit repairs and maintenance were not originally tracked. Establishing an accurate data base for the time period prior to automation proved impossible after the study was complete.

Oil Production Increase

The installation and operation of the SCADA system enabled the Unit oil and gas production to increase in a range from 3.8% to 13.9% (Fig. 1). This increase was a direct result of reduced downtime, better overall surveillance and better overall operational efficiency. All factors which could affect production other than the SCADA system were simultaneously considered and are discussed below.

Determining a single production increase value would be incorrect due to potential differences in data interpretation. Therefore, the range of the minimum and maximum oil and gas production increase was identified. The capabilities of the SCADA system which enabled Sun to increase daily oil and gas production between 3.8% and 13.9% are summarized under the benefits in Table 1.

The oil production increase between a minimum of 3.8% and a maximum of 13.9% excludes drilling, exceptionally high workover effect and high production increases due to any high water injection volume increase. Also, water production increases were analyzed. Drilling effects were eliminated by analyzing the production of only the 134 well base throughout the five-year study. The 134 well base was used because it reflects the number of wells producing in January 1980. In April 1985, as a result of infill drilling from 1980 to 1985, the 134 well base represented 69.0% of the total producing wells.

The oil production of the 134 well base was determined by applying the percent difference between the monthly total Unit's oil production and oil test to the monthly sum of the 134 well base oil tests throughout the five-year period.

The percent difference between monthly Unit test and Unit production reflects both the downtime in producing wells and the accuracy in tests. The average percent difference between Unit oil test and oil production decreased 23.0%. This 23.0% decrease in percent difference reflects both less downtime from decreased failures and quicker response time and better test accuracy from more frequent accurate testing ability. The decreased downtime is reflected as increased average daily production.

The 3.8% increase (minimum) was determined by comparing actual production against expected production on the 134 well base. The oil production decline rate was calculated for the time period from July 1981 to April 1983. This decline rate was then used to calculate the expected production without the SCADA system for October 1983 using actual production for July 1981 as a starting point. The actual production for October 1983 with the SCADA system was then compared to the calculated production without the SCADA system for October 1983.

The maximum increase of 13.9% was also determined by comparing actual production against expected production but the decline rate was determined for a different time period than that used to determine the minimum increase. The oil production decline rate was calculated for the time period from October 1983 to April 1985 for the 134 well base. This decline rate was used to calculate the expected production without the SCADA system for October 1983 using actual production for October 1982 as a starting point. The actual production for the 134 well base for October 1983 was then compared to the calculated value without the SCADA system.

The water production of the 134 well base would also be expected to increase from the SCADA system installation as a result of the reduced downtime, better well surveillance, and better operational efficiency. The water production for the 134 well survey increased between a minimum of 3.8% and a maximum of 15.2% immediately following the SCADA system installation. The increase in water production was determined similar to the oil production increase and further verifies that reduced downtime and improved operational efficiencies have been achieved.

Workover results were examined for their effects upon the production increase. The workover results are not sufficient to increase the production greater than 1.5% above normal production and is consistent throughout the five years. Potential tests after completion of the workover could increase the Unit oil production 3.4% in 1983 and 4.9% in 1984. However, production tests one month following potential reflect an increase of below 1.5% in both years. Due to the highest possible effect of 1.5%, the workover effects were not considered.

Unit water injection was examined during the time period of 1980 to 1985 for its possible effect on the production increase. Total water injection increased by approximately 7000 BWIPD (1113 m^3/d) in the Fall of 1981. The water injection increase in 1981 was the only significant increase during the time period of 1980 to 1985. The normal production response time in the SELU from increased water injection is four to six months. The SCADA system was in complete operation 18 months after the increased water injection. The response in oil production resulting from the SCADA system installation immediately followed installation (Fig. 1). The oil production increase came 18 months rather than four to six months after increased water injection. Therefore, the percent oil production increase shown by the SCADA system installation did not reflect the expected oil and gas production resulting from increased injection.

Had the effects of increased water injection upon the oil production shown up after the SCADA system installation, the maximum effect would be a 3.2% increase. This increase is based upon a 1 BOPD (m^3/d) produced for every 20 BWIPD (m^3/d). It should also be noted that the I/W is continually declining throughout the five-year study (Fig. 2).

Adjustments to the oil production were not made for the increased water injection because: (1) the time period between the increased water injection and the increased oil production due to the SCADA system installation was 18 months rather than four to six months and (2) the declining I/W.

Decreased Power Consumption

The average monthly power consumption per barrel of fluid lifted on the Unit decreased by 11.3% (Fig. 3). The decrease was determined by tracking the actual monthly invoices for electrical usage during the five-year study. The power usage of the electrical motor (1000 HP [746 KW]) powering the horizontal split-case centrifugal pump used for water injection was subtracted from the total monthly KWH (J) usage. This was done to provide actual power consumption attributable to producing wells to be used in calculating power savings due to POC. The monthly KWH (J) usage was then divided by each total monthly Unit fluid production volume.

Because of increasing daily fluid production, the total power consumption (KWH [J] only) may not decrease. However, the monthly average power consumption per barrel of fluid lifted (KWH/bbl [J/m^3]) does decrease, indicating a power consumption decrease per barrel of fluid (J/m^3) lifted of 11.3%. This was accomplished through more efficient pump time provided by the POC.

Decreased Subsurface Failures

Overall failures per barrel (m^3) of fluid lifted decreased 28.6% after installation of the SCADA system (Fig. 4). Failures of the 134 well base were analyzed on a failure rate per barrel (m^3) of fluid lifted. This was done because average monthly fluid production per well rose 3.0% while percent water cut rose 3.9%.

The fluid production and water cut increases were determined by comparing the average fluid production for the time period prior to against fluid production during the time period following the SCADA system installation.

The SCADA system allowed the average rate of increase in failures to be decreased by 116.0% in addition to reducing the monthly average failure rate per barrel (m^3) of fluid lifted by 28.6%.

All failures were analyzed over the five-year period with the time period prior to automation being 30 months. The failure rate reduction per barrel (m^3) of fluid lifted was determined on the 134 well base 12 months prior to, and 24 months following the SCADA system installation. The average from the 12 month period was used rather than the average from the 30 month period because of the dramatic subsurface failure rate of increase in the 30 month period prior to automation (Fig. 4).

Increasing rod and tubing life were considered during the analysis of the subsurface failure rates. Average rod and tubing string life for the Unit is 12.0 years and 12.5 years respectively. Nineteen percent of the rod strings and 21.0% of the tubing strings have been in service for more than 35 years. Eighty percent of the rod strings and 86.0% of the tubing strings are original installations.

The overall failure rate reduction due to the SCADA system installation independent of fluid production was 25.5%. Wells shown in Table 4 were analyzed for failure rate characteristics independent of fluid production prior to and following the SCADA system installation.

The SCADA system enabled Sun to decrease the subsurface failure rate dramatically on wells with high failure rates but the decrease was offset by the failure rates on wells with no failures which began to fail as a result of increased water cut, increased rod and tubing life, and increased production. The four groups (2, 3, 4 & 5) in Table 4 had total failure rates decrease by greater than 40.0%.

The SCADA system enabled Sun to decrease the subsurface failure rate through the following capabilities: (1) POC; (2) tracking pumps after repairs from well to well; (3) loading alarms; and (4) improved paraffin and scale program (less rod stress).

Decreased Pumping Unit Repairs & Maintenance And Increased Pumping Unit Utilization

The SCADA system enabled the segment team to survey the wells (loading, speed, vibration, bearing, fraying bridles) as often as deemed necessary. As a result, a greater number of extreme and damaging gearbox overloads were isolated and eliminated by exchanging the units. The system provided greater volumes of accurate data to enable the segment team to more efficiently utilize pumping units. This lowered the maintenance capital which would normally be used in an operation of less efficient pumping unit utilization.

By monitoring bearings, vibration and bridle fraying, lower pumping unit repair cost and fewer downhole failures occur. Frequently, failures were prevented by the computer operator who detected these potential problems before they occurred.

Due to these benefits not being tracked as stated previously, they were not considered in the economic evaluation.

INTANGIBLE BENEFITS

The SCADA system allows for benefits other than the tangible items previously identified.

Special projects, such as a motor survey performed on well #21 by Sun's Electrical Engineering Department, can be performed effectively as a result of the system. The system enabled torque, well test and daily run times to be tracked efficiently and accurately in the evaluation of the optimum electric motor to be used on oilfield pumping units. This resulted in one of the most complete product evaluations performed by Sun to date because of the SCADA system capabilities.

Areas in which the system allows the computer operator to perform certain tasks which directly improve daily operating and production efficiencies are numerous. These areas are listed under Benefits in Table 1.

Dunham [17] describes how a Computer Production Control (CPC) system can assist in reducing the communication gap between operations and engineering. By allowing more timely collection and greater volumes of accurate data, the system could be utilized for the following:

1. Reservoir studies
2. Determining effects of increased water injection
3. Prediction of permeability trends
4. Improved accurate comparison of water-flood patterns in a field
5. Determining effects of infill drilling upon existing production
6. New product evaluations

COSTS

The costs associated with this system are installation and regular maintenance costs. The installation cost was $1.9MM and included all aspects of installation (Table 1). Monthly maintenance costs include increased manpower (intangible - $6,300/mo.) for daily upkeep of the system (tangible - $3,605/mo.), monthly computer software maintenance ($1,040/mo.), and monthly computer hardware maintenance ($683/mo.) (Table 1).

CONCLUSIONS

The advantages of the SCADA system installed on the SELU far outweigh the costs involved. The exact degree of the net benefits resulting from a similar system will depend upon production operations prior to installation as Neely [13] has stated previously. If the tendency prior to automation was to pump at capacity or under pump with the use of percentage timers, less reduction in power and maintenance costs, but greater increases in production would result. However, if the tendency is to extremely over-pump the wells (pumping 24 hours/day), power and maintenance cost reductions will be greater.

Through the least optimistic perspective possible (i.e. 3.8% oil production increase), Sun applied an economic analysis to the benefits and costs identified, assuming pure production acceleration. A 3.22 year payout with a ROR greater than 50.0% was revealed. Had a more optimistic view been taken, or had the analysis considered additional recoverable reserves,[9,11,18] the results would have been dramatically better.

The tangible benefits of the operation of the system are a result of faster and more accurate data acquisition, increased volumes of accurate data, improved operational efficiency and greater operational potential.

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Table 1
Computerized Automation of Oilfield Productions — Costs & Benefits

PAYOUT

- BENEFITS
  - TANGIBLE
  - INTANGIBLE
- COST
  - INITIAL INVESTMENT
  - ONGOING

TANGIBLE

(A. DECREASED OPERATING EXPENSES AND INCREASED INCOME)
(B. BASE CASE MAINTENANCE CAPITAL DECREASE)

1. INCREASE OIL AND GAS PRODUCTION
   a. Decreased downtime from decreased subsurface failures
   b. Detect low pump efficiency more quickly
   c. Detect gas locking problems more quickly
   d. Detect casing check valve leak more quickly
   e. Detect trash in pump more quickly
   f. Detect standing or traveling valve problem in pump more quickly
   g. Detect collapsed casing more quickly
   h. Detect casing leak more quickly
   i. Higher quality and quantity test and test history to identify and plan work from
   j. Immediate problems alarms
   k. Ability to isolate wells down and place back on production after a power failure
   l. Detect crossed flowlines at first installation (better data)
   m. Detect high or low rates on injection wells more quickly
   n. Detect plugged filters or injection lines on water injection wells
   o. Detect large leaks in injection lines more quickly
   p. Detect paraffin problems in the flowline more quickly
   q. Detect wellbore scale buildup more quickly
   r. Detect tubing leaks and parts more quickly
2. DECREASE POWER CONSUMPTION
3. DECREASED SUBSURFACE FAILURE RATE
   a. POC
   b. Loading alarms
   c. Ability to track pumps from well to well more quickly
   d. Ability to detect paraffin problems in tbg. and rods more quickly
   e. Ability to detect scale buildup in the pump and tbg. more quickly
   f. Ability to detect tubing travel more quickly
   g. Ability to detect sticking pump more quickly
   h. Ability to detect pump tagging bottom more quickly
   i. Ability to detect p.u. problems prior to failure more quickly
   j. Ability to detect all overloads prior to failure more quickly
4. DECREASED P.U. REPAIRS AND MAINTENANCE
   a. Detect bearing failure prior to failure
   b. Detect bridle failure prior to failure
   c. Detect downhole overloads to prevent gearbox overloads
   d. Detect belts slipping or off
5. MAXIMIZE EQUIPMENT UTILIZATION

INTANGIBLE

1. DETECT PROBLEMS ON SATELLITE STATIONS IMMEDIATELY
   a. Back pressure valve leaking
   b. Three way valve leaking
   c. Pump failure
   d. Power failure
   e. Header valve leaking
   f. N.O.C. failure
   g. High vessel pressure
   h. Accurate test
   i. Immediate alarms
2. DETECT CENTRAL BATTERY PROBLEMS IMMEDIATELY
   a. Tank levels
   b. Injection volumes
   c. Production volumes
   d. Check line and vessel pressure
3. POSSIBLE USES CURRENTLY UNDER STUDY
   a. Monitor cathodic protection
   b. Control injection volumes
   c. Monitor H_2S
   d. Monitor flowline pressure
4. POSSIBLE PROJECTS OR RESERVOIR STUDIES
   a. Establish directional permeability trends
   b. Detect possible water channels from injection to producing wells
   c. Establish possible relation between pump sticking problem to stress failure
   d. Effects of infill drilling upon offset production
   e. Motor evaluations
   f. Comparison of waterflood patterns

INITIAL INVESTMENT

1. COMPUTER AND PERIPHERALS
2. TELEMETRY EQUIPMENT
3. INJECTION WELL END DEVICES
4. PRODUCTION WELL END DEVICES
5. CABLE INSTALLATION
6. JUNCTION BOXES AND MISCELLANEOUS HARDWARE
7. TEST EQUIPMENT AND SPARES
8. SOFTWARE LICENSE
9. SOFTWARE IMPLEMENTATION
10. LABOR

ONGOING

1. INCREASED MANPOWER COST
2. MONTHLY TANGIBLE COST OF SYSTEM MAINTENANCE
   (Tangible cost only - Intangibles are considered in manpower cost)
   - A. POC
     1. RTU
        a. Logistic board
        b. Calibration
        c. Fuses
     2. LOAD CELL AND CABLE
        a. Repairs or replacement
        b. Cable repairs
     3. POSITION POT. & CABLE
        a. Repairs or replacement
        b. Alignment
     4. FIELD CABLE CUTS
        a. Replace cable
   - B. TEST STATIONS
     1. Mechanical failures (Automation Only)
     2. Electrical failures
        a. Equipment repairs or replacement
     3. Net oil computer
        a. Equipment repairs or replacement
     4. RTU boards
        a. Equipment repairs or replacement
     5. AWT panel
        a. Equipment repairs or replacement
     6. Fuses
        a. Replacement
     7. Field cable cuts
        a. Cable replacement
   - C. INJECTION WELLS
     1. Rate
        a. Turbine meter rates and pickup
        b. Frequency to DC converter
        c. Cable
        d. Calibration
     2. Pressure
        a. Transmitter
        b. Cable
        c. Calibration
     3. Field cable cuts
     4. RTU boards
     5. Fuses
   - D. MISCELLANEOUS
     1. Cleaning fluids
     2. Spare electronics parts
   - E. MONTHLY COMPUTER SOFTWARE MAINTENANCE
   - F. MONTHLY COMPUTER HARDWARE MAINTENANCE

Table 2
Data Examined During Study

1. The 134 well base monthly oil and water tests.
2. Total unit well tests vs. unit actual production with percent difference between tests and actual production for oil, water and total fluid.
3. Unit injection to withdrawal ratio.
4. Increased unit water injection effects.
5. Workover results.
6. Average unit fluid production percent water cut increase.
7. Average unit fluid production increase.
8. KWH (J) usage per barrel (m3) of fluid lifted.
9. Subsurface failure rate on 134 well base (rods, tubing and pump) (The 134 well base is the number of producing wells in January, 1980, the initial date of data gathering prior to automation.)
10. Subsurface failure rate (total failures, total rods, tubing, rod body and pump) for each category of wells having low, medium and high volume production.
11. Percent run time, BFPD(m3/d), BOPD(m3/d) and types of subsurface failures for 10 wells with low volume production (0-75 BFPD(0-11.9m3/d)), 10 wells with medium volume production (76-150 BFPD(12.0-23.8m3/d)), and 10 wells with high volume production (151 BFPD(24.0m3/d)and over).
12. Failure rate on the 20 wells in the unit with the highest failure rate history.
13. Rod and tubing life.
14. Chemical treating (corrosion).
15. P.U. maintenance and repair costs.
16. Increasing manpower costs.
17. SCADA system maintenance costs.

Table 3
Data Gathering and Automation Installation Timetable

January	1980	Subsurface failure rate documentation began on a 134 well base. (The 134 well base was the total number of producing wells in January, 1980.)
November	1980	Cable and system installation began.
July	1981	Production and test data documentation began; electrical usage invoices documented.
July	1982	First producing wells on POC. First satellite station on computer control.
October	1982	First injection wells on computer.
April	1983	All production wells on POC and central computer.
June	1983	All satellite stations and injection wells on computer.
October	1984	Central battery, LACT units, tank level, produced water volumes, total water injection volumes on computer.
April	1985	All documentation ceased.

Table 4
Subsurface Failure Rate Data Analysis

A. CATEGORY	AVE. TOTAL FAILURE RATE PER YEAR PER BBL. (m^3) FLUID LIFTED PRIOR TO INSTALLATION	AVE. TOTAL FAILURE RATE PER BBL (m^3) OF FLUID LIFTED AFTER INSTALLATION	% DECREASE IN FAILURE RATE PER BBL. (m^3) OF FLUID LIFTED
I. 134 Well Survey	1.73 E-5	1.24 E-5	28.6%

B. CATEGORY	AVE. TOTAL FAILURE RATE PER YEAR PRIOR TO INSTALLATION (August 1981 to July 1982)	AVE. TOTAL FAILURE RATE PER YEAR AFTER INSTALLATION (May 1983 to April 1985)	% DECREASE OF FAILURE RATE/YR. NOT CONSIDERING FLUID PRODUCTION
I. 134 Well Survey			
A. Total Failures (Tubing, rods, polish rods, pump)	102.0	76.0	25.5%
B. Tubing	12.0	6.1	49.2%
C. Rods			
Total rod failures incl/polish rods	47.0	35.2	25.1%
Total rod failures excl/polish rods	45.0	31.2	30.7%
D. 3/4" Rods	32.0	17.9	44.1%
E. 7/8" Rods	12.0	11.3	5.8%
F. 1" Rods	1.0	2.0	100.0% Increase
G. Pump	43.0	34.8	19.1%
II. 20 Well w/Highest Failure Rate	44.0	26.0	40.5%
III. 10 Low Volume Wells	9.0	1.0	85.6%
IV. 10 Medium Volume Wells	27.0	10.0	63.0%
V. 10 High Volume Wells	24.0	14.0	45.0%

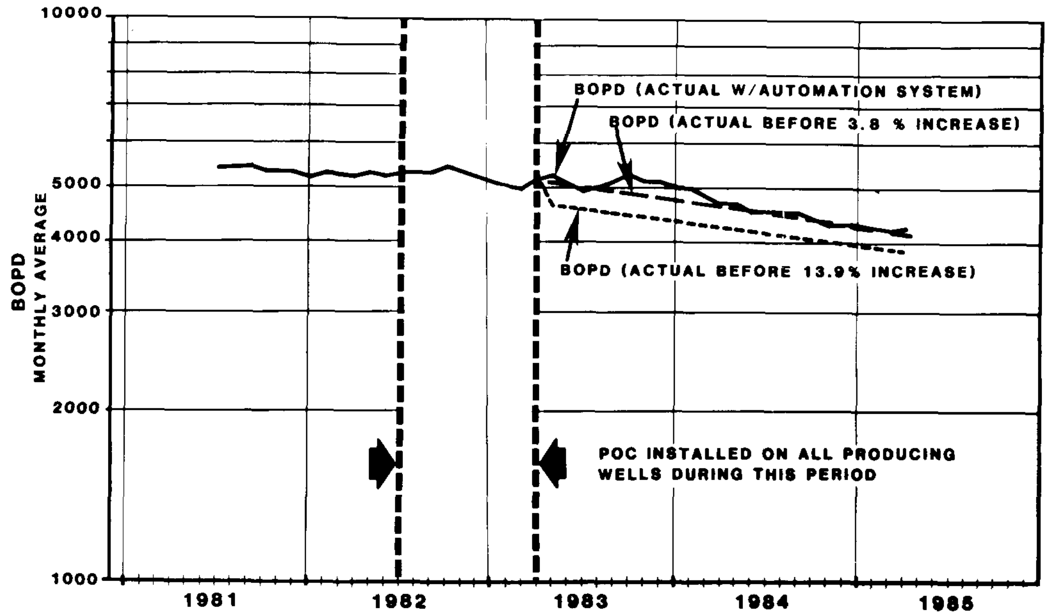

Figure 1—SELU—comparison of the minimum and maximum oil production increases for the 134 well base

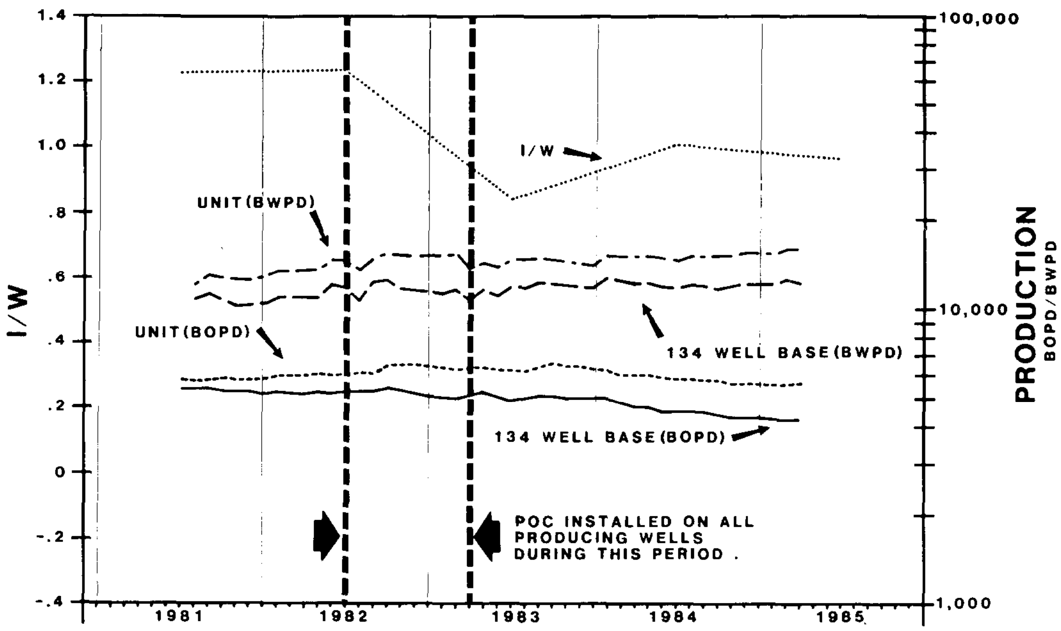

Figure 2—SELU—I/W, 134 well base oil and water production, and total unit oil and water production

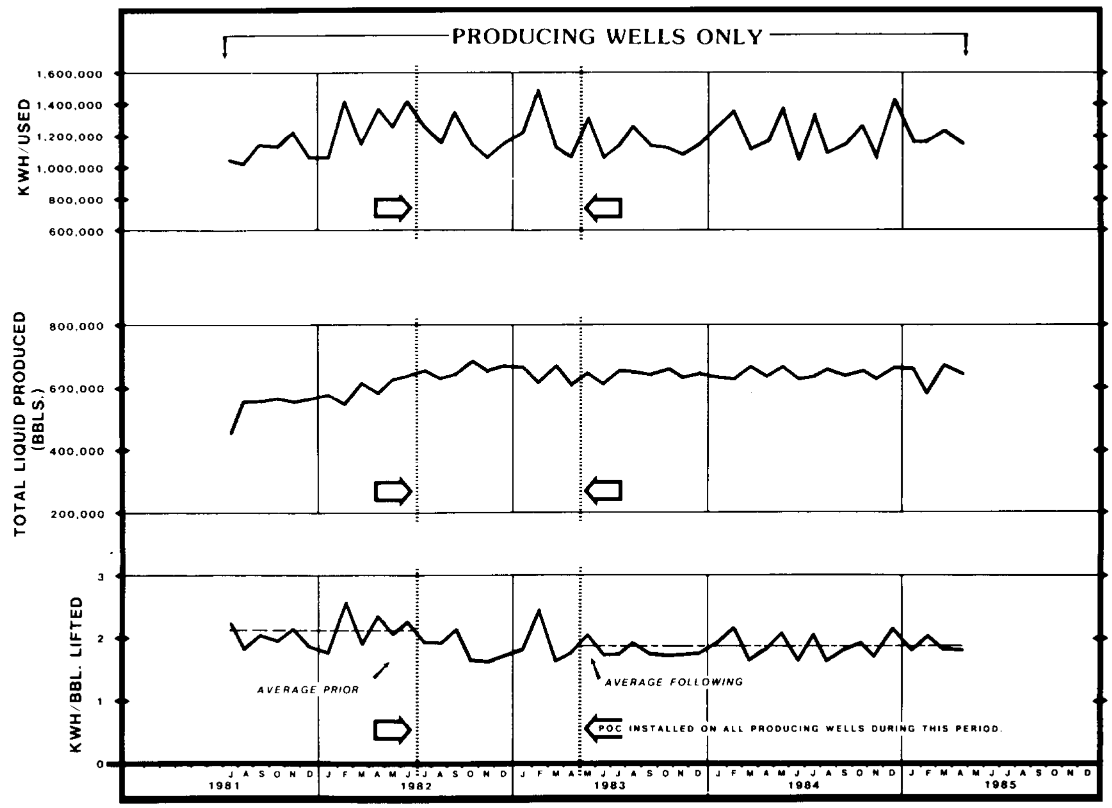

Figure 3—SELU—KWH usage per barrel of fluid lifted for all producing wells in the unit

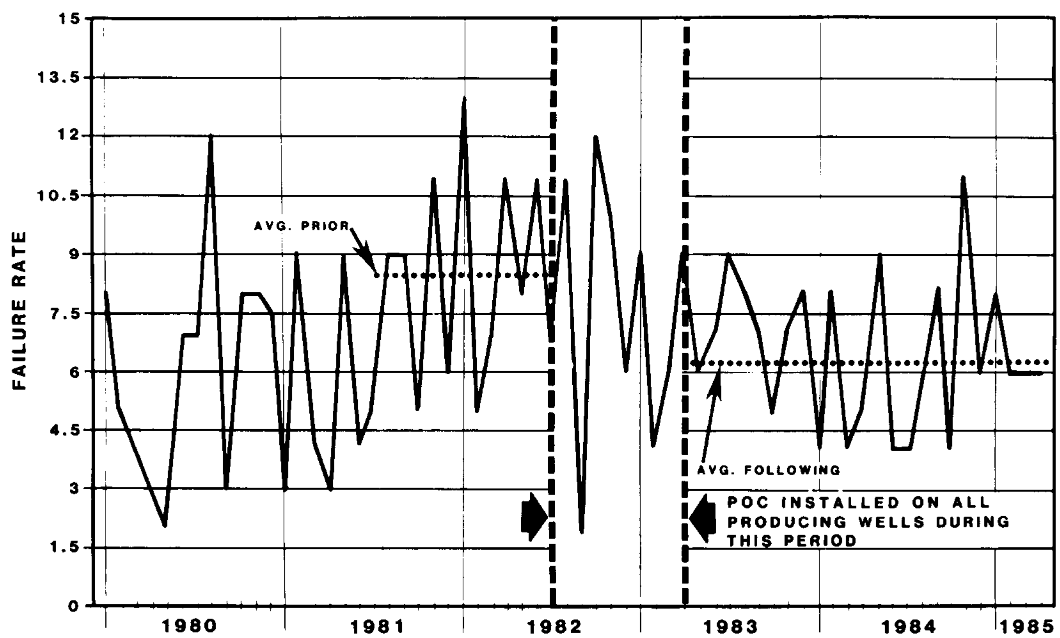

Figure 4—SELU—monthly subsurface failure rate for the 134 well base